Electricity Market Report

July 2002

Electricity
Oversight Board

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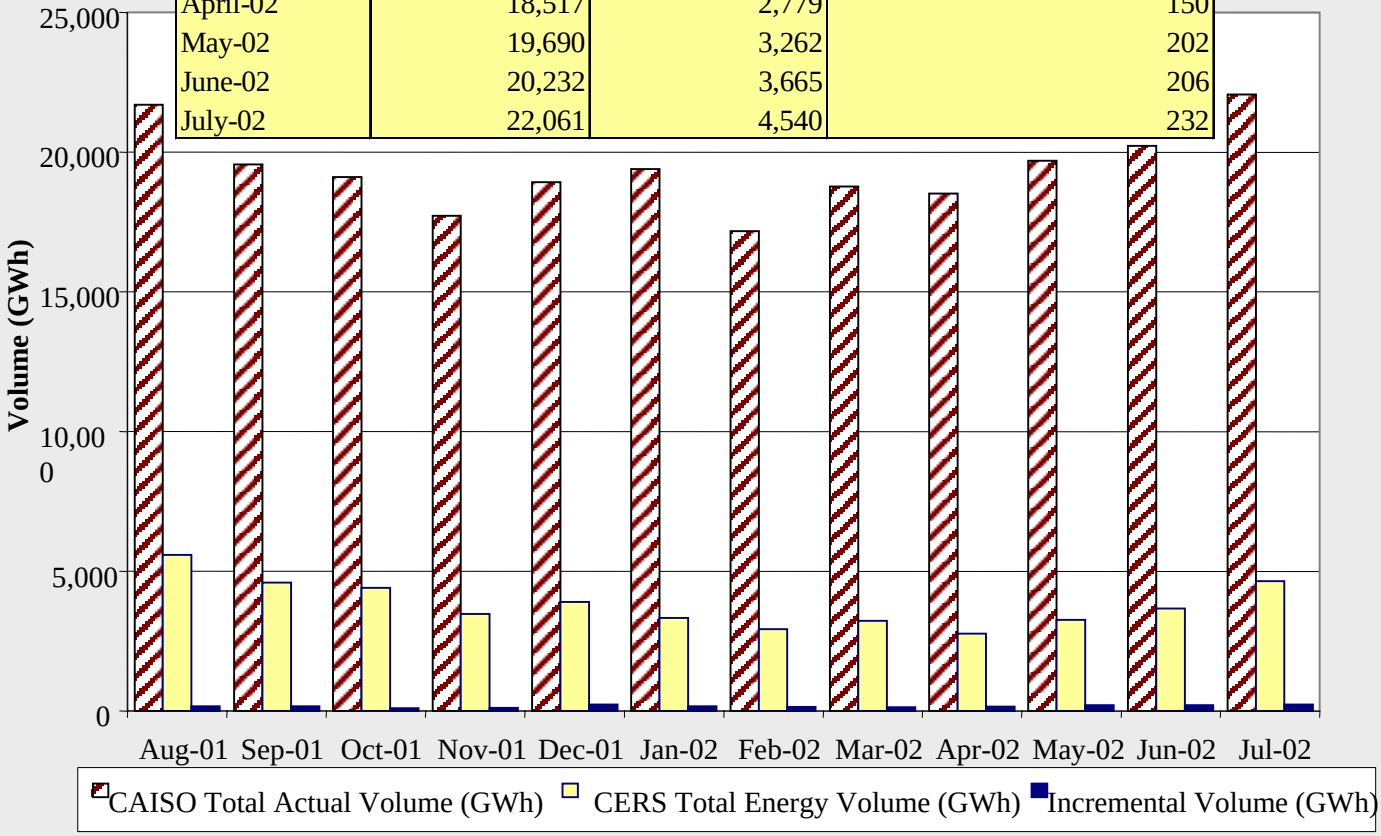
California Energy Market by Total Volume

Period	*CAISO Total Actual Volume (GWh)	CERS Total Energy Volume (GWh)	**CAISO Real-Time BEEP Incremental Volume (GWh)
August-01	21,689	5,580	172
September-01	19,562	4,607	171
October-01	19,105	4,402	104
November-01	17,717	3,471	109
December-01	18,919	3,898	228
January-02	19,386	3,329	158
February-02	17,178	2,933	146
March-02	18,767	3,222	137
April-02	18,517	2,779	150
May-02	19,690	3,262	202
June-02	20,232	3,665	206
July-02	22,061	4,540	232



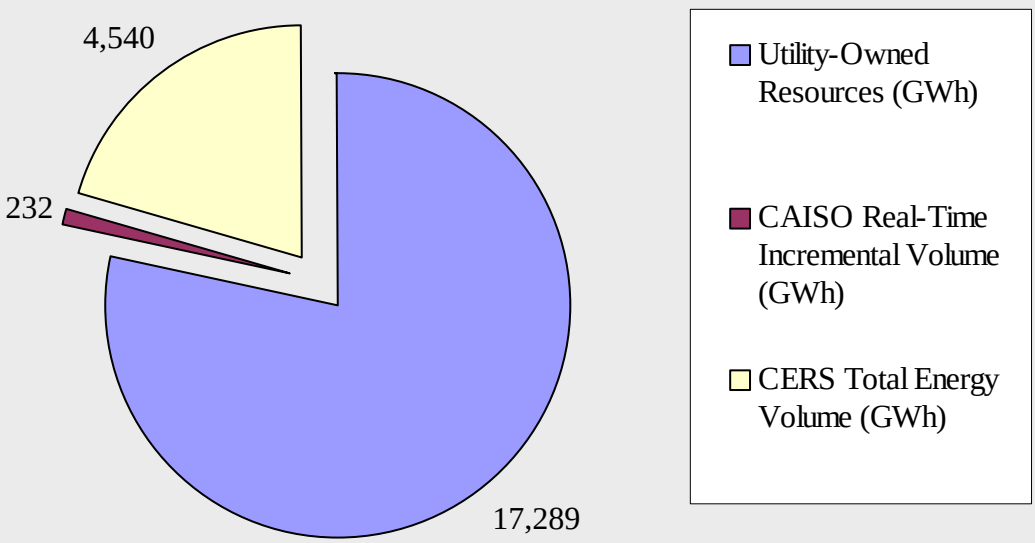
The CAISO actual total volume experienced a 5-percent year-over-year increase, from 20,970 GWh in July 2001 to 22,061 GWh in July 2002. The CAISO actual total volume increased by 9 percent in July over June, followed by CERS total energy volume at 26 percent and CAISO real-time BEEP incremental volume at 13 percent.

*CAISO Total Actual Volume: Sum of all energy for the CAISO Control Area, in MWh, over a period of time.
**Real-Time Market: The competitive generation market controlled and coordinated by the CAISO for arranging real-time imbalance power.

Source: California Independent System Operator. System Load Report July 1, 2002 – July 31, 2002: Online. OASIS. September 2002.
California Independent System Operator. Ex-Post 10-Minute Price Information July 1, 2002 – July 31, 2002: Online. OASIS. September 2002.
California Department of Water Resources. CERS Detailed Purchase Power Report. Sacramento: California Department of Water Resources 2002.

Percentage of CAISO Actual Load by Category

Percent of CAISO Total Actual Volume by Category			
Period	CAISO Real-Time Incremental Market	CERS Total Energy Market	Utility-Owned Resources
August-01	0.8%	25.7%	73.5%
September-01	0.9%	23.6%	75.6%
October-01	0.5%	23.0%	76.4%
November-01	0.6%	19.6%	79.8%
December-01	1.2%	20.6%	78.2%
January-02	0.8%	17.2%	82.0%
February-02	0.8%	17.1%	82.1%
March-02	0.7%	17.2%	82.1%
April-02	0.8%	15.0%	84.2%
May-02	1.0%	16.6%	82.4%
June-02	1.0%	18.1%	80.9%
July-02	1.1%	21.0%	77.9%



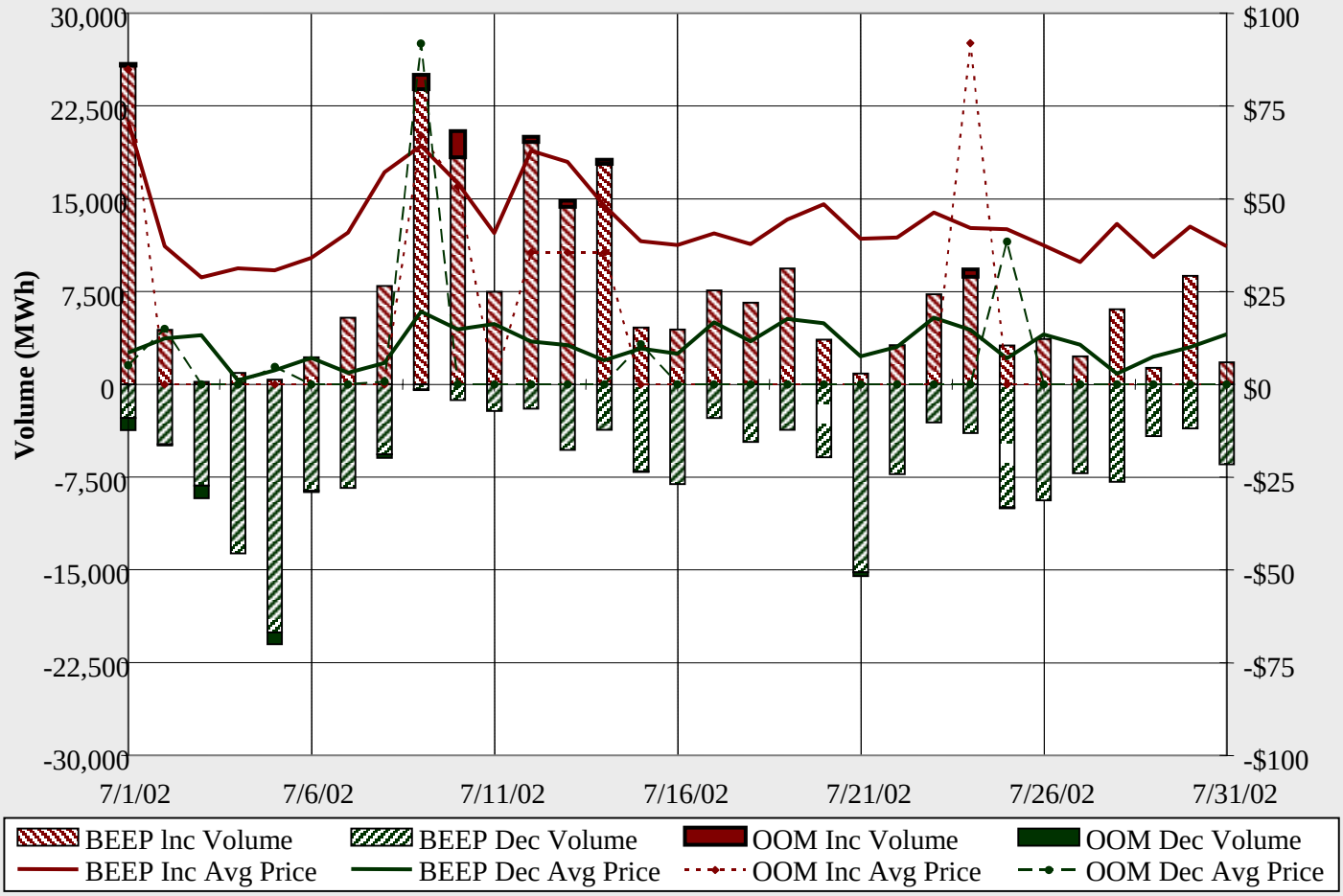
July 2002

The CAISO real-time incremental volume and CERS total energy market made up more than 22 percent of the CAISO monthly total actual load in July. The remainder of the total CAISO load (78 percent) is served by utilities that balance load and resources within their service territory.

Source: California Independent System Operator. System Load Report July 1, 2002 – July 31, 2002: Online. OASIS. September 2002.
California Independent System Operator. Ex-Post 10-Minute Price Information July 1, 2002 – July 31, 2002: Online. OASIS. September 2002.
California Department of Water Resources. CERS Detailed Purchase Power Report. Sacramento: California Department of Water Resources 2002.

CAISO Real-Time Prices and Volumes for Incremental and Decremental Energy Markets

CAISO Real-Time Energy Market	Real-Time BEEP		Real-Time OOM		Total	
	Inc	Dec	Inc	Dec	Inc	Dec
Volume (MWh)	231,724	197,172	5,192	3,941	236,916	201,113
Average Price ($/MWh)	$51.79	-$8.67	$57.42	-$4.83	$51.92	-$8.59



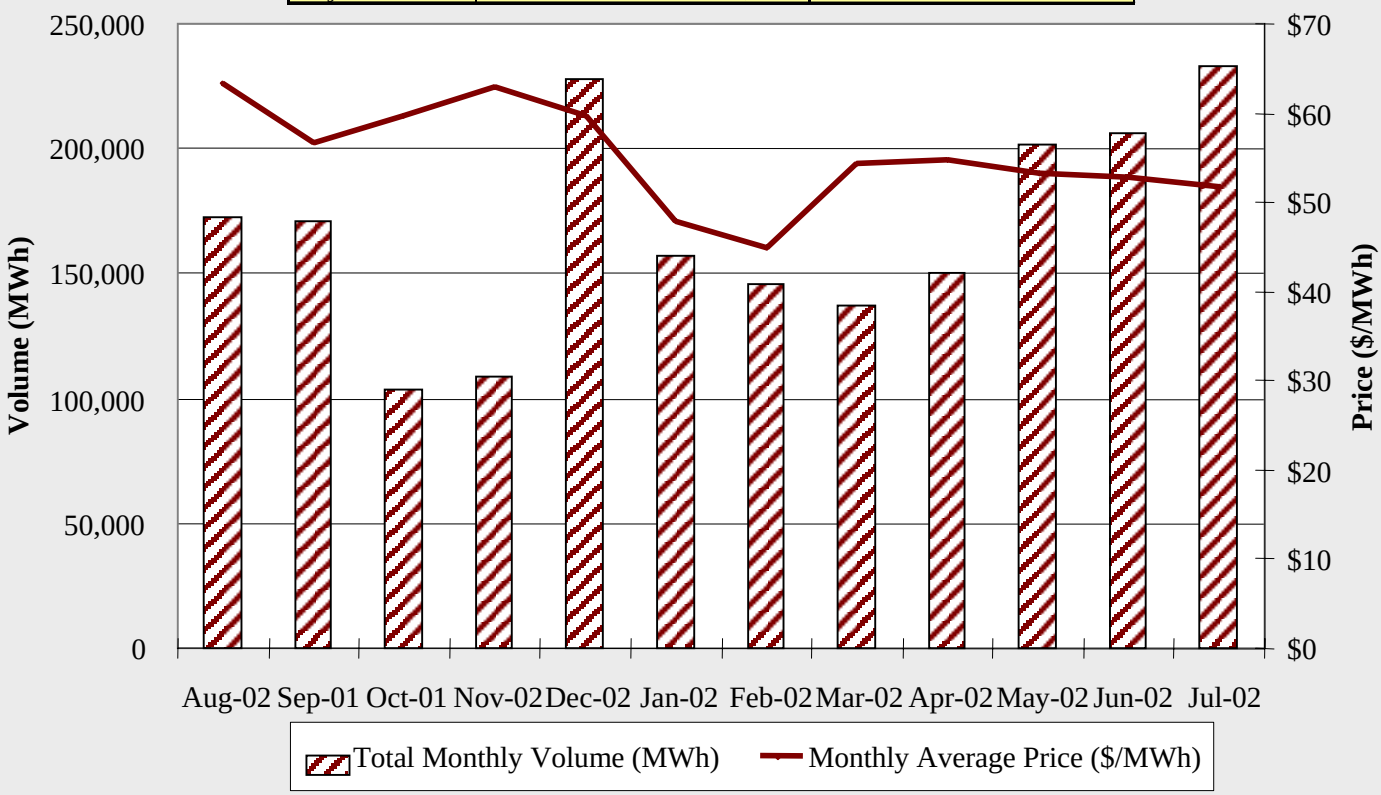
The CAISO real-time total incremental volume at 237 GWh increased by 13 percent from June, while the average price remained fairly unchanged. The CAISO real-time total decremental volume at 201 GWh decreased by 23 percent from June, whereas the average price increased by 55 percent. The real-time incremental daily average prices peaked on July 1, and July 9 through July 13. This could be the result of warmer temperatures across California, higher prices, and average hourly unit outages at roughly 4,000 MW.

Source: California Independent System Operator. Ex-Post 10-Minute Price Information July 1, 2002 – July 31, 2002: Online. OASIS. September 2002.

California Independent System Operator. CAISO Data July 1, 2002 – July 31, 2002. August 2002.

CAISO Real-Time BEEP Incremental Market Statistics

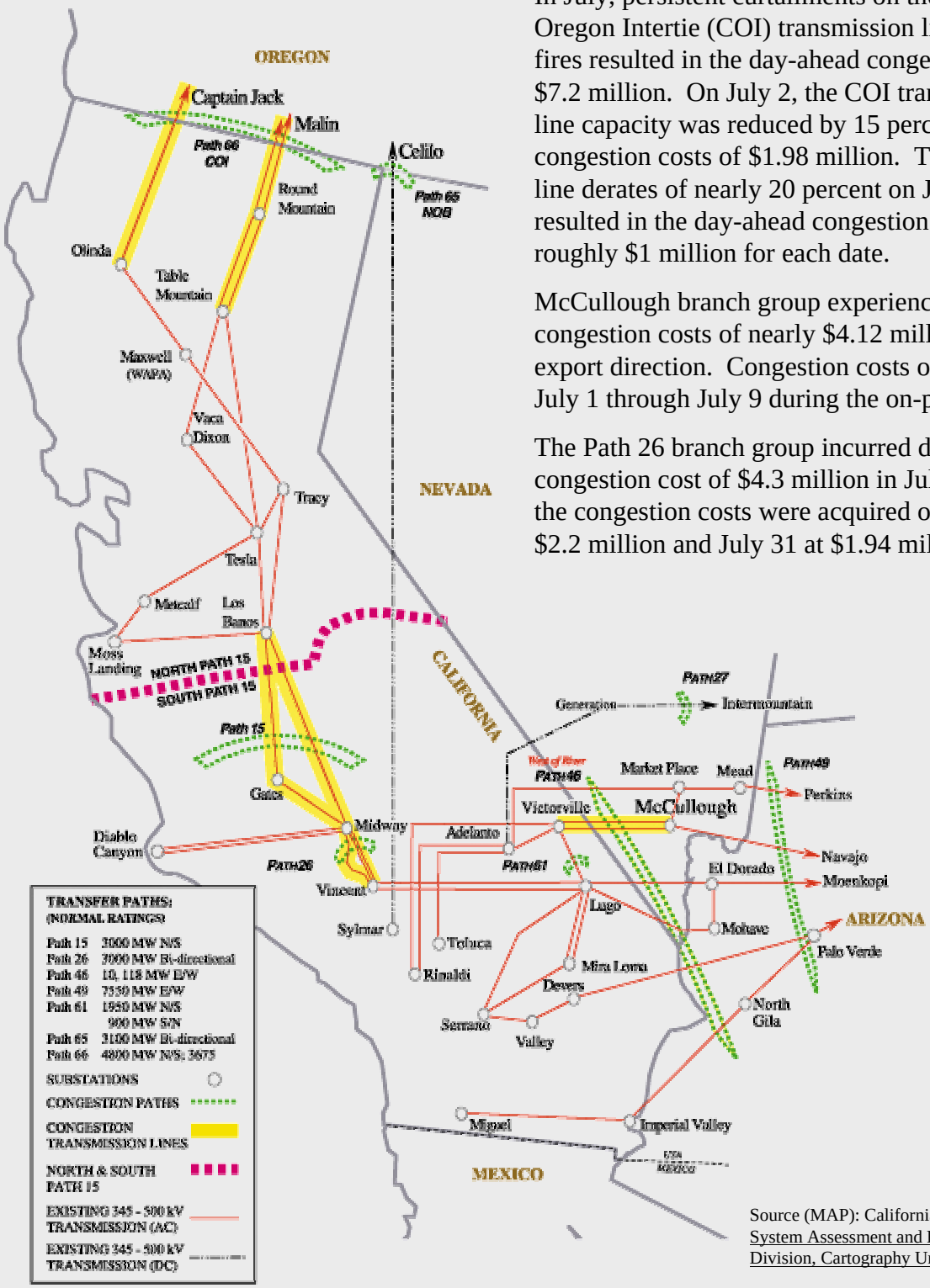
Period	CAISO BEEP Incremental Energy Market	
	Total Monthly Volume (MWh)	Monthly Average Price ($/MWh)
August-01	172,470	$63.25
September-01	170,879	$56.76
October-01	103,759	$59.63
November-01	109,068	$62.85
December-01	227,744	$59.60
January-02	157,526	$47.96
February-02	145,874	$44.88
March-02	137,121	$54.31
April-02	149,967	$54.73
May-02	201,684	$53.28
June-02	206,161	$52.78
July-02	231,724	$51.79



The average price for the CAISO real-time BEEP incremental energy market has remained stable over the past five months ranging from $51.79 to $54.73/MWh, while the total monthly volume has gradually increased by 70 percent from March through July 2002.

Source: California Independent System Operator. Ex-Post 10-Minute Price Information July 1, 2002 – July 31, 2002: Online. OASIS. September 2002.

Selected California Transmission Lines



In July, persistent curtailments on the California-Oregon Intertie (COI) transmission line due to fires resulted in the day-ahead congestion cost of $7.2 million. On July 2, the COI transmission line capacity was reduced by 15 percent leading to congestion costs of $1.98 million. Transmission line derates of nearly 20 percent on July 9 and 13 resulted in the day-ahead congestion cost of roughly $1 million for each date.

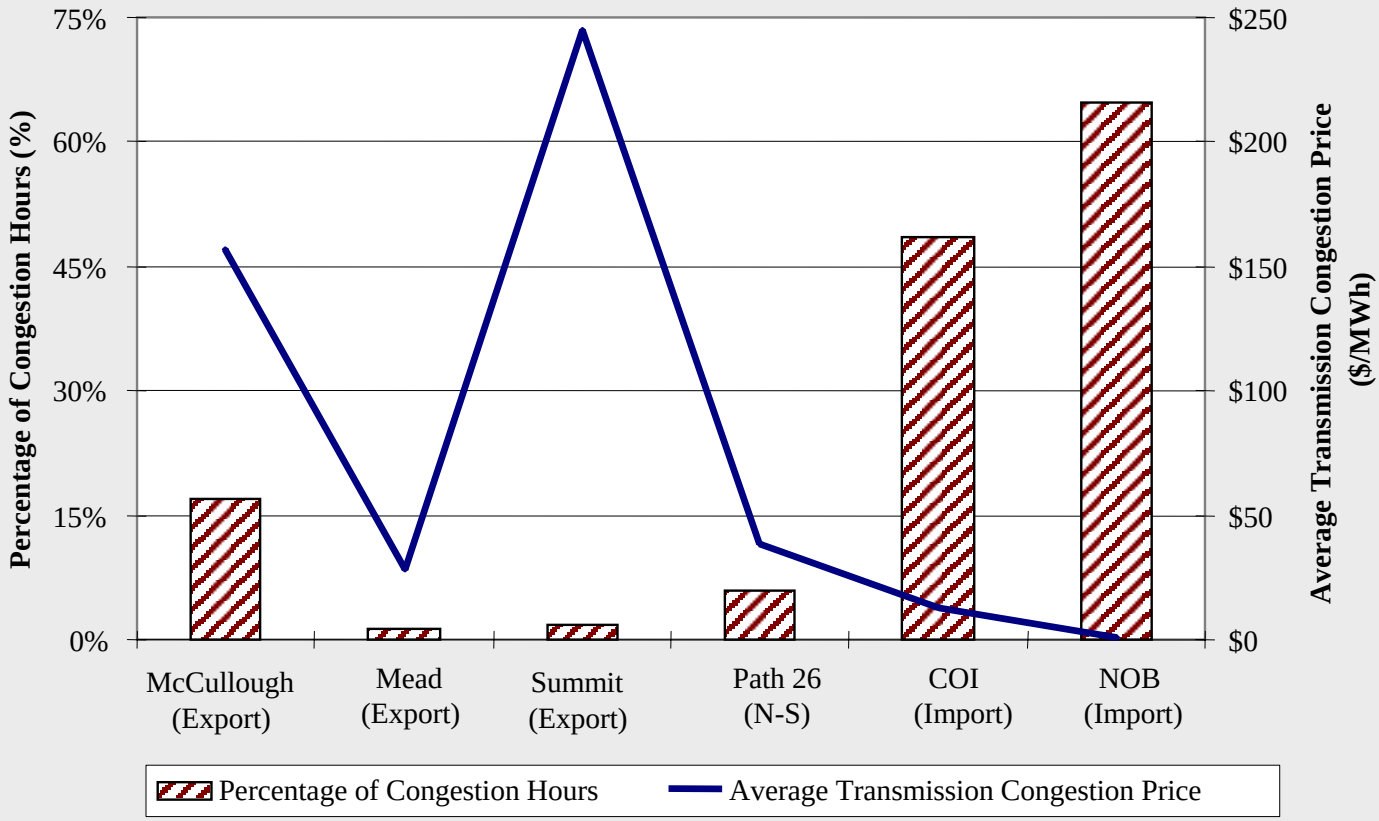
McCullough branch group experienced day-ahead congestion costs of nearly $4.12 million in the export direction. Congestion costs occurred from July 1 through July 9 during the on-peak period.

The Path 26 branch group incurred day-ahead congestion cost of $4.3 million in July. Nearly all the congestion costs were acquired on July 16 at $2.2 million and July 31 at $1.94 million.

Source (MAP): California Energy Commission. System Assessment and Facilities Siting Division, Cartography Unit October 2002.

CAISO Congestion Frequency, Prices, and Cost

Branch Group	Number of Hours of Congestion	Percentage of Congestion Hours	Average Transmission Congestion Price ($/MWh)	Day-Ahead Adjustment Congestion Cost ($)
McCullough (Export)	126	16.9%	$156.41	$4,117,445
Mead (Export)	9	1.2%	$28.11	$222,465
Summit (Export)	13	1.7%	$245.00	$318,596
Path26 (N-S)	43	6.0%	$38.88	$4,301,299
COI (Import)	350	48.6%	$13.24	$7,163,248
NOB (Import)	466	64.7%	$0.96	$698,424



The COI branch group incurred the heaviest monthly total congestion costs in July 2002 at roughly $7.2 million followed by Path 26 and McCullough, each at roughly $4 million.

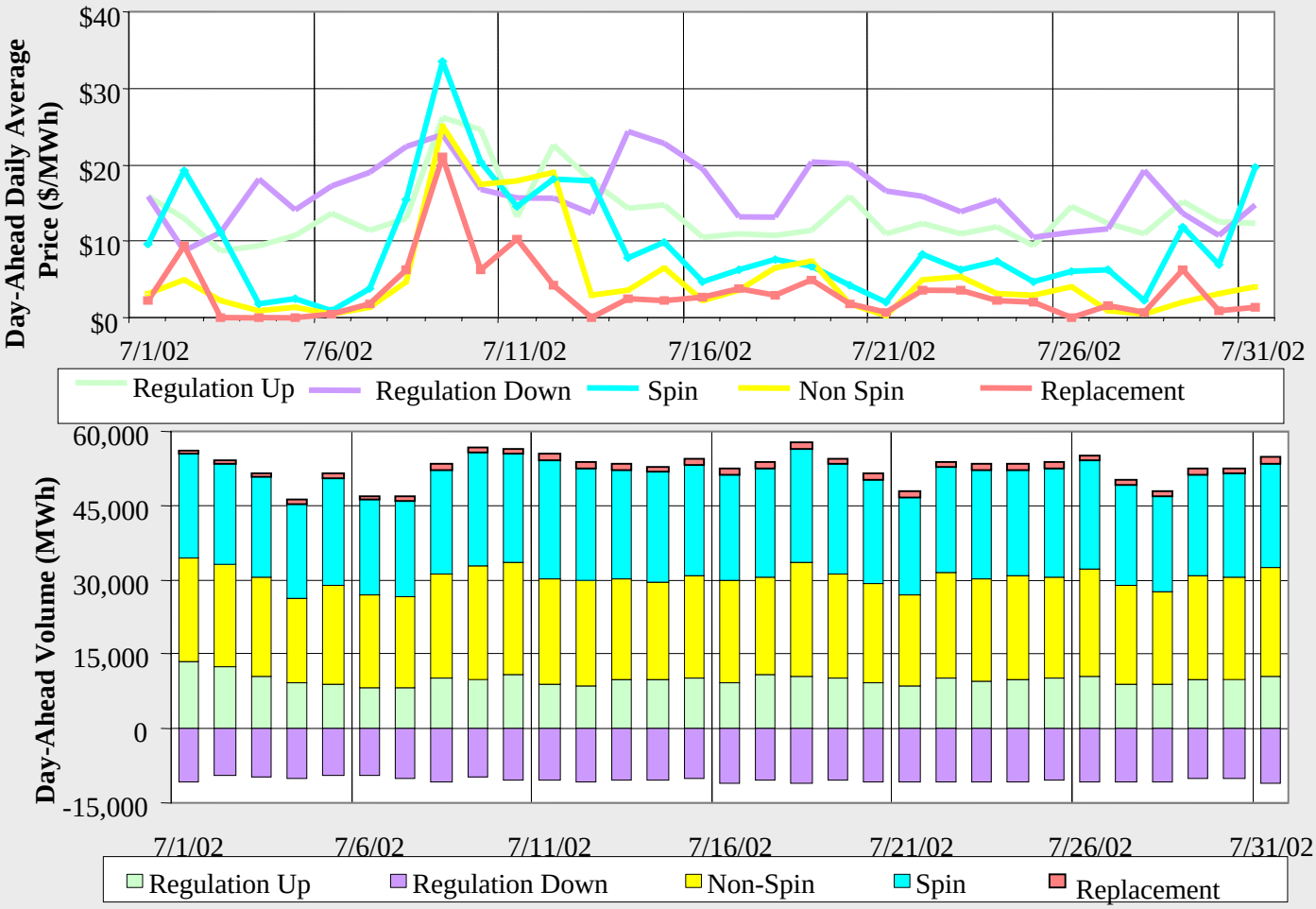
The COI transmission line was derated due to fires near the Oregon border in the north-to-south direction, which limited imports into California. The Path 26 and McCullough branch groups experienced congestion due to warmer weather conditions that lead to higher load in the southern California and southwest regions.

Source: California Independent System Operator. Branch Group Congestion Market Summary July 1, 2002 – July 31, 2002: Online. OASIS. September 2002.

California Independent System Operator. Actual Scheduled Flow July 1, 2002 – July 31, 2002: Online. OASIS. September 2002.

Ancillary Services Statistics

July 2002 Ancillary Services Market Segment	Average Price ($/MWh) Day-Ahead	Hour-Ahead	Total	Average Hourly MW Day-Ahead	Hour-Ahead	Total	Percent Purchased in Day-Ahead	Percent of Market Segment Over Total A/S
Regulation Up	$14.98	$14.56	$14.95	413	19	432	96%	16%
Regulation Down	$16.61	$13.93	$16.38	435	32	467	93%	17%
Spin	$10.77	$6.57	$10.53	886	39	925	96%	34%
Non-Spin	$6.37	$4.97	$6.32	854	18	872	98%	32%
Replacement Reserve	$3.21	$1.00	$2.89	44	2	46	95%	2%
Total				2,631	111	2,742	96%	100%



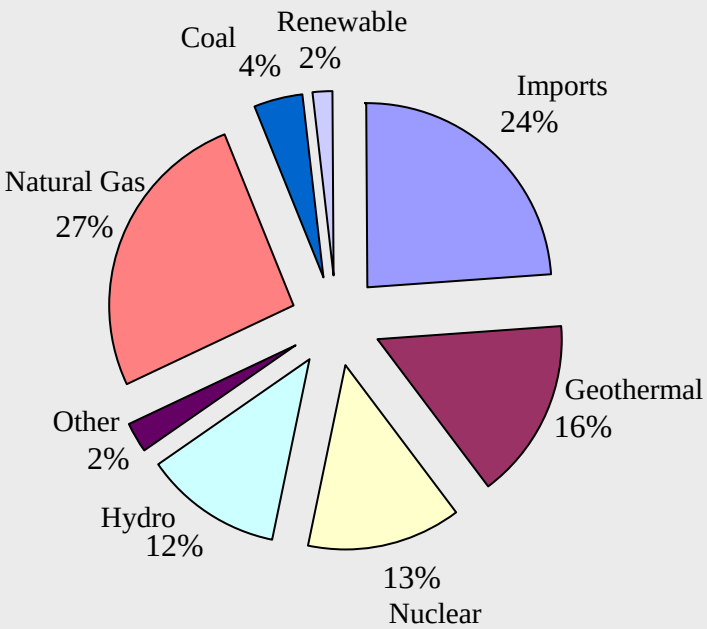
In July, the weighted average price for the total ancillary services market segments increased by 14 percent at $10.76/MWh from $9.45/MWh in June. The total hourly average load increased by 5 percent to 2,742 MW in July, up from 2,622 MW in June. The average price and percent of market segment over total volume dropped for regulation up, while it increased for spin and non-spin market segments.

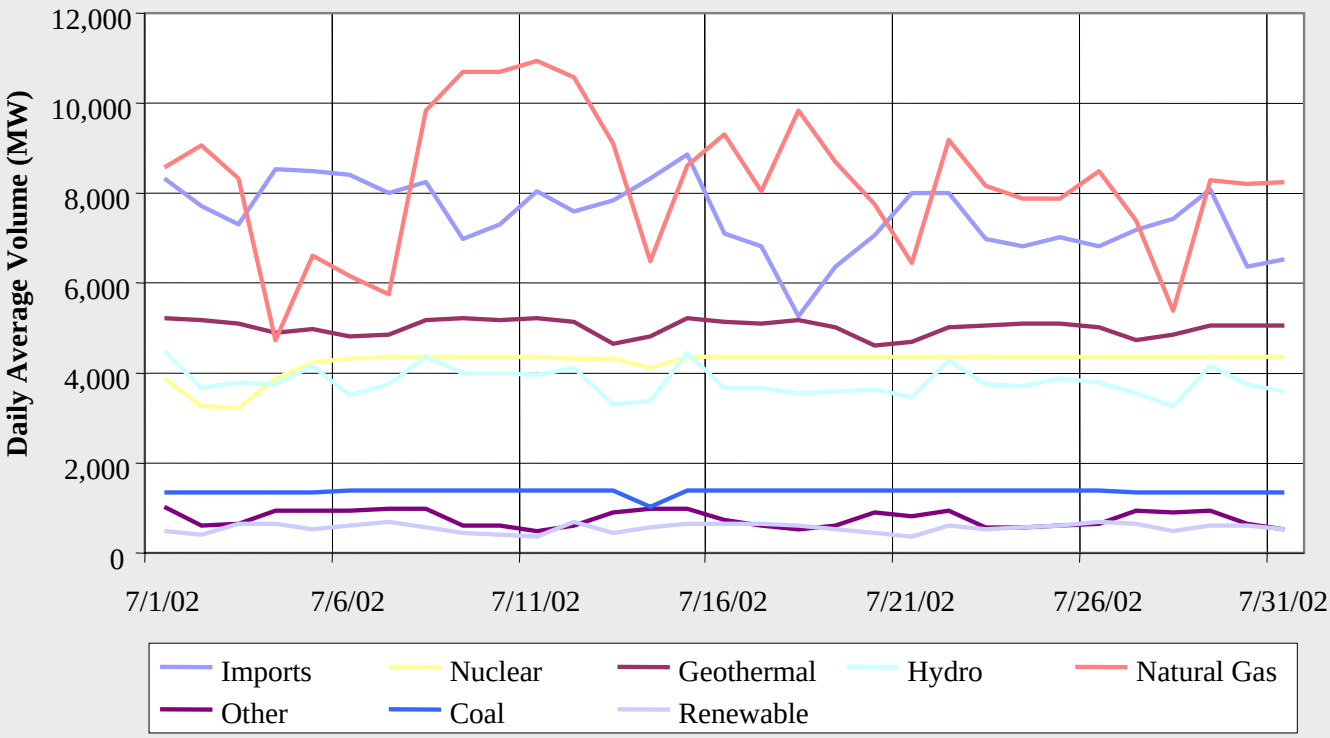
A price spike on July 9 corresponds with increased temperatures in addition to significant unplanned outage capacity.

Source: California Independent System Operator. CAISO Data July 1, 2002 – July 31, 2002. August 2002.

CAISO Day-Ahead Resource Mix

July 2002 Resource Mix	Day-Ahead Market Monthly Total Volume (GWh)	Day-Ahead Market Percent Share of Total
Natural Gas	6,128	26.2%
Imports	5,564	23.7%
Geothermal	3,735	15.9%
Nuclear	3,156	13.5%
Hydro	2,832	12.1%
Coal	1,018	4.3%
Other	571	2.4%
Renewables	415	1.8%





In July, California generating unit output remained fairly stable for all but natural gas. The peak observed for natural gas unit generation output concurred with warm weather conditions across California. Natural gas and imports made up roughly 50 percent of the total monthly volume for July.

Source: California Independent System Operator. CAISO Data July 1, 2002 – July 30, 2002. August 2002.

CERS Daily Average Price and Total Expenditures

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In July, the daily average cost for the CERS total energy market increased by 7 percent to $78.79/MWh from June, while the total energy volume increased by 24 percent to 4,540 MWh.

Warmer weather conditions in northern California resulted in increased load from July 8 through July 13 leading to higher daily total expenditures. This was despite moderate daily average prices for this period.

*CERS Total Energy Market includes: CERS spot (out of market, hour-ahead, and day-ahead) and forward (contracts, balance of month and quarterly) market purchases.

Source: California Department of Water Resources. CERS Detailed Purchase Power Report. Sacramento: California Dept. of Water Resources 2002.

CERS Volume Purchased by Market Segment

Redacted from Public Version Due to Confidential Data

The Fourth of July holiday that extended through the weekend resulted in lowered demand for July 4 through July 7. As a result, the CERS sold its day-ahead, hour-ahead, and OOM, which reduced the excess generation for these dates.

Source: California Department of Water Resources. CERS Detailed Purchase Power Report. Sacramento: California Department of Water Resources 2002.

CERS Forward Market Statistics

Redacted from Public Version Due to Confidential Data

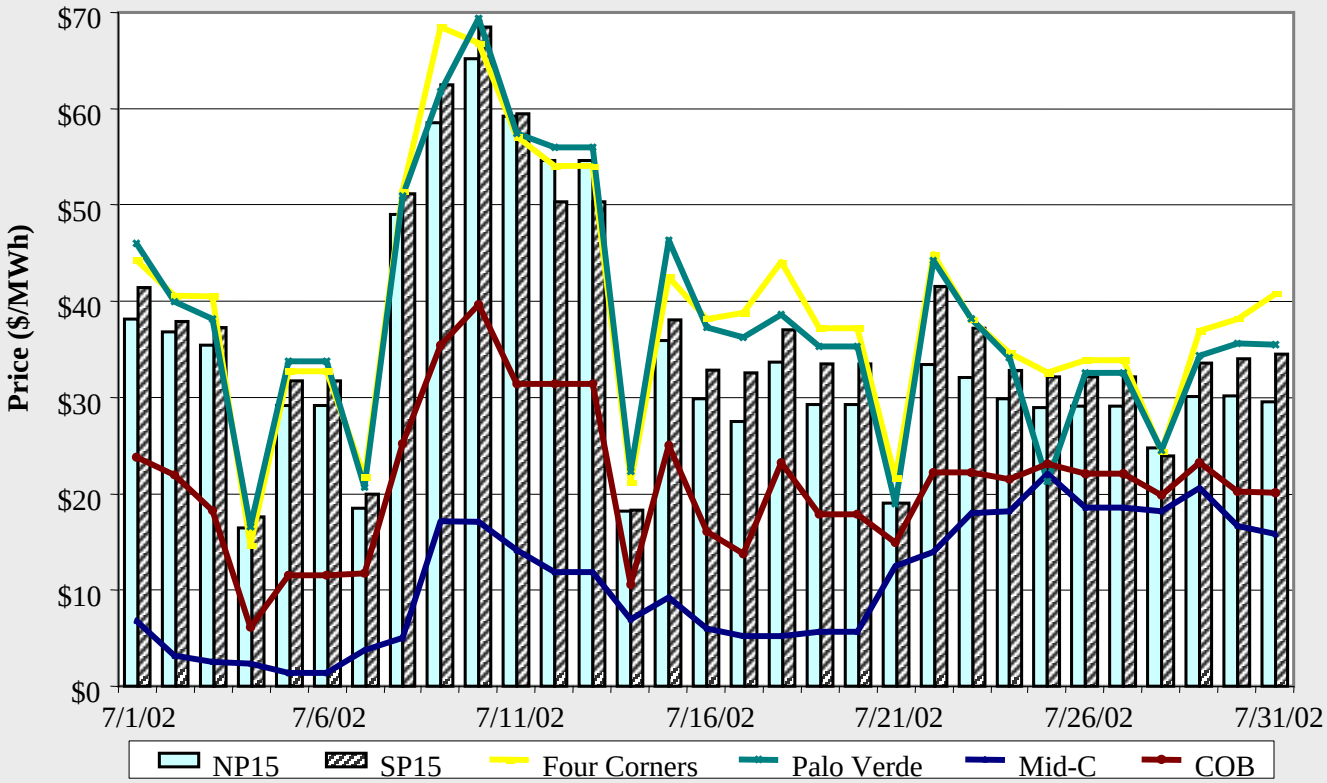
In July, the average price for the CERS balance of the month and quarterly purchases increased by 24 percent to $45.86/MWh from June at $37.07/MWh. The average price for the CERS contracts moderately increased by 4 percent.

The total monthly volume for the CERS contracts increased by 25 percent, while the CERS balance of the month and quarterly volume increased by 125 percent in July, up from June.

Source: California Department of Water Resources. CERS Detailed Purchase Power Report. Sacramento: California Department of Water Resources 2002.

Regional Hubs On-Peak Daily Average Prices

July 2002 Regional Hubs	On-Peak Average Price ($/MWh)	On-Peak Total Volume (MW)	Percent Difference from Prior Month
NP15	$34.35	35,425	23%
SP15	$36.74	44,575	21%
COB	$21.14	21,975	6%
Mid-C	$10.84	79,600	20%
Palo Verde	$38.18	49,563	19%
Four Corners	$39.30	6,425	24%



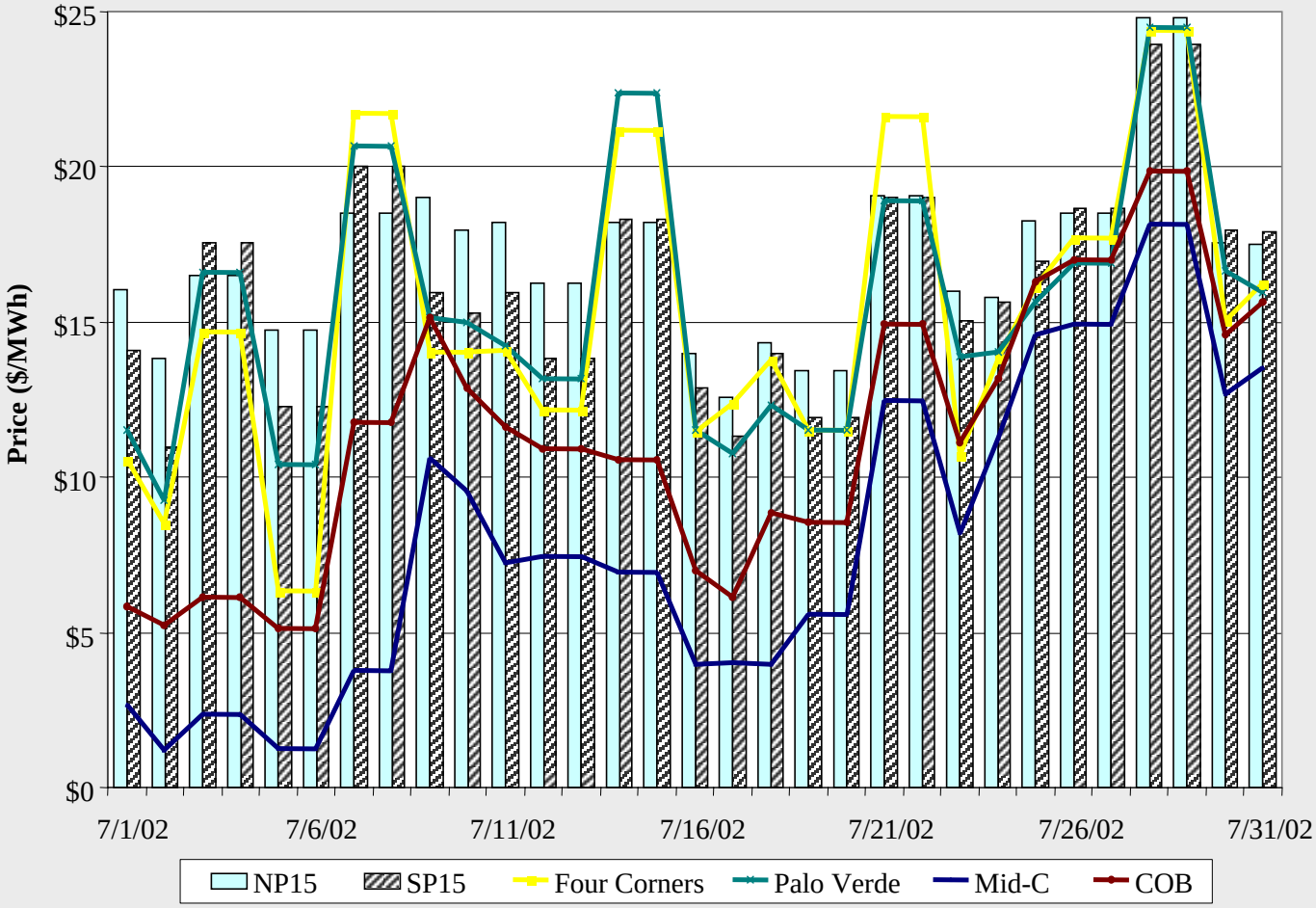
The average daily prices experienced a steep increase from July 8 through July 13 as a result of warm temperatures across California and the southwest. In July, the electric indices average price increased by roughly 6 percent for COB and between 20 to 25 percent for the remaining regional hubs, up from June. Palo Verde experienced the greatest total volume increase over the last month at 38 percent, followed by Mid-C at 33 percent.

Four Corners, Palo Verde, and SP15 experienced higher average prices than the remaining hubs. This could be the result of transmission line constraints on COI that limited less-expensive hydroelectric imports into California, warmer temperatures in the southwest and southern California leading to higher loads, and unplanned unit outages. The northwest hubs, COB, and Mid-C benefited from lower gas prices and ample hydroelectric generation.

Source: Energyonline. Dow Jones Electricity Indices. July 1, 2002 – July 31, 2002: Online. Energyonline. August 2002.

Regional Hubs Off-Peak Daily Average Prices

July 2002 Regional Hubs	Off-Peak Average Price ($/MWh)	Off-Peak Total Volume (MW)	Percent Difference from Prior Month
NP15	$17.13	25,638	12%
SP15	$16.29	23,975	32%
COB	$11.40	19,650	29%
Mid-C	$8.05	35,450	86%
Palo Verde	$15.68	17,250	39%
Four Corners	$15.27	5,375	44%



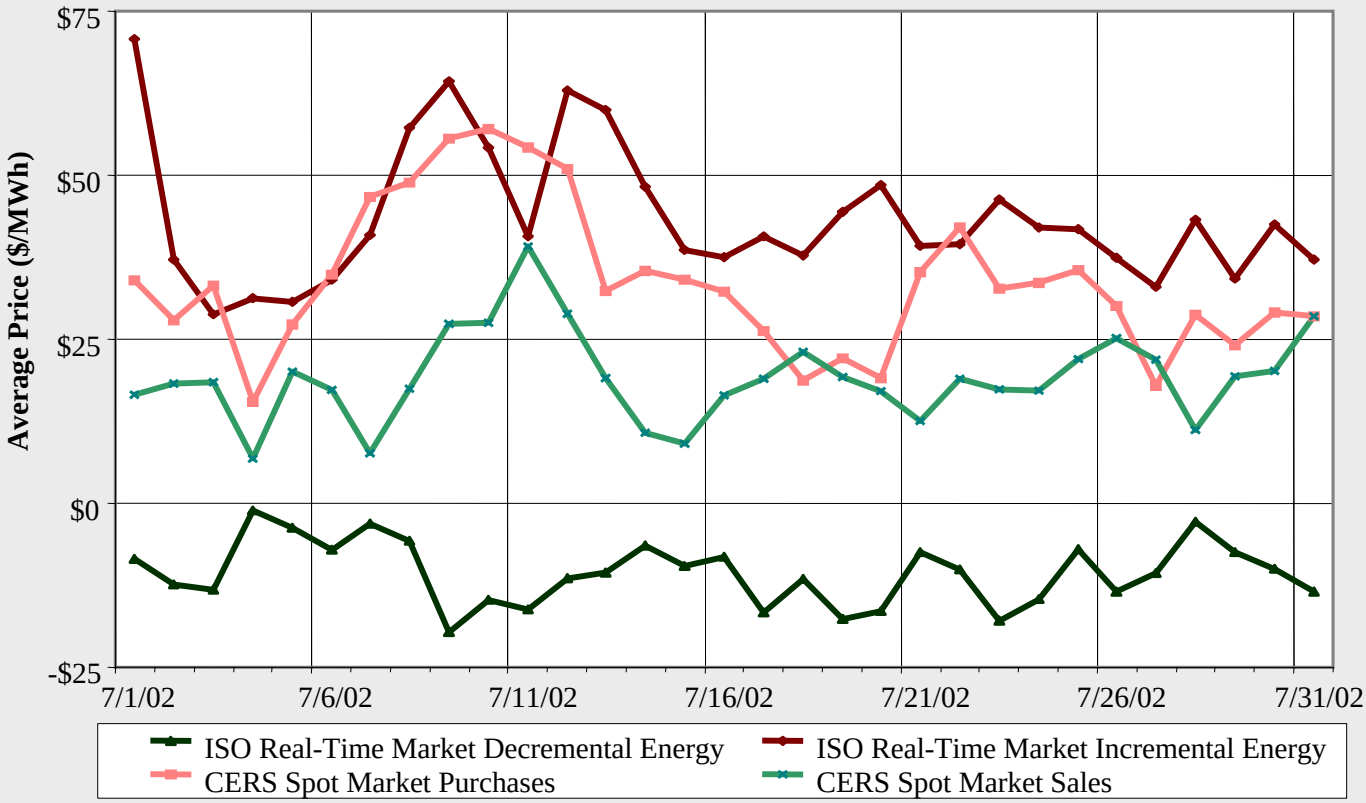
In July, the greatest off-peak average price increase occurred at Mid-C at 86 percent, followed by Four Corners at 44 percent and Palo Verde at 39 percent, up from June. The greatest total volume increase occurred at NP15, which increased by 40 percent. The daily average prices for the off-peak period began to converge on July 24, and continued through July 28. This could be the result of lower hydro generation in the northwest, which required the higher-priced gas generating units to come on line.

Source: Energyonline. Dow Jones Electricity Indices. July 1, 2002 – July 31, 2002: Online. Energyonline. August 2002.

Daily Average Prices for CERS Spot Energy vs. CAISO BEEP Energy Market

July 2002 CERS SPOT Market	Purchases Volume (MWh)	Purchases Average Cost ($/MWh)	Sales Volume (MWh)	Sales Average Cost ($/MWh)
Out of Market	2.7	$24.07	0.0	$0.00
Hour-Ahead	227.9	$25.81	185.3	$18.29
Day-Ahead	286.2	$49.32	322.7	$19.17
Total	516.8	$38.82	508.0	$18.85

CAISO Real-Time Energy Market	Incremental Volume (MWh)	Incremental Average Cost ($/MWh)	Decremental Volume (MWh)	Decremental Average Cost ($/MWh)
BEEP	231,724	$51.79	197,172	-$8.67



The average price for the CERS day-ahead purchase jumped by 58 percent in July, up from June. The higher daily average prices for the CERS spot market occurred from July 8 continuing through July 13, and July 21 continuing through July 26, which concur with warmer temperatures, as well as significant unplanned outages.

Source: California Independent System Operator. Ex Post 10-Minute Price Information July 1, 2002 – July 31, 2002: Online.OASIS. September 2002.
California Department of Water Resources. CERS Detailed Purchase Power Report. Sacramento: California Department of Water Resources 2002.

CERS Forward Market vs. Spot Index*

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In July, the Dow Jones electric index total monthly volume at 362 MWh increased by 5 percent from June. The daily average price of $22.44/MWh increased by 15 percent. The CERS balance of the month and quarterly total monthly volume increased by 117 percent and the daily average prices increased by 23 percent.

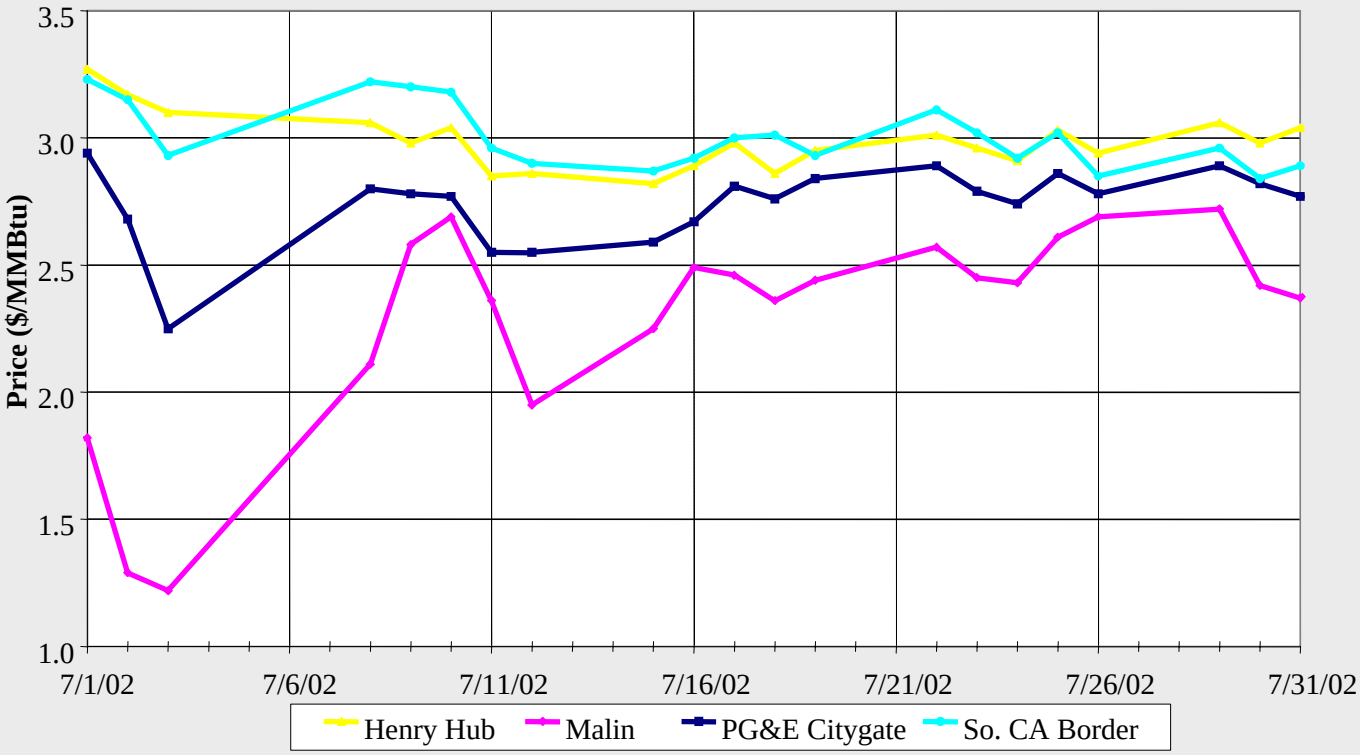
The dip in the CERS daily average price on July 4 was a result of lower loads associated with the Fourth of July holiday. The Dow Jones daily average price experienced higher prices for the period of July 8 through July 13 as a result of warm temperatures in California and the southwest.

*Note: Weighted average prices at major hubs including NP15, SP15, COB, PV, Mid-C, and Four Corners.

Source: Energyonline. Dow Jones Electricity Indices. July 1, 2002 – July 31, 2002: Online. Energyonline. August 2002.
California Department of Water Resources. CERS Detailed Purchase Power Report. Sacramento: California Department of Water Resources 2002.

Natural Gas Prices

July 2002	Malin	PG&E Citygate	So. CA Border	Henry Hub
Monthly Average Prices ($/MMBtu)	$2.30	$2.74	$3.01	$2.99



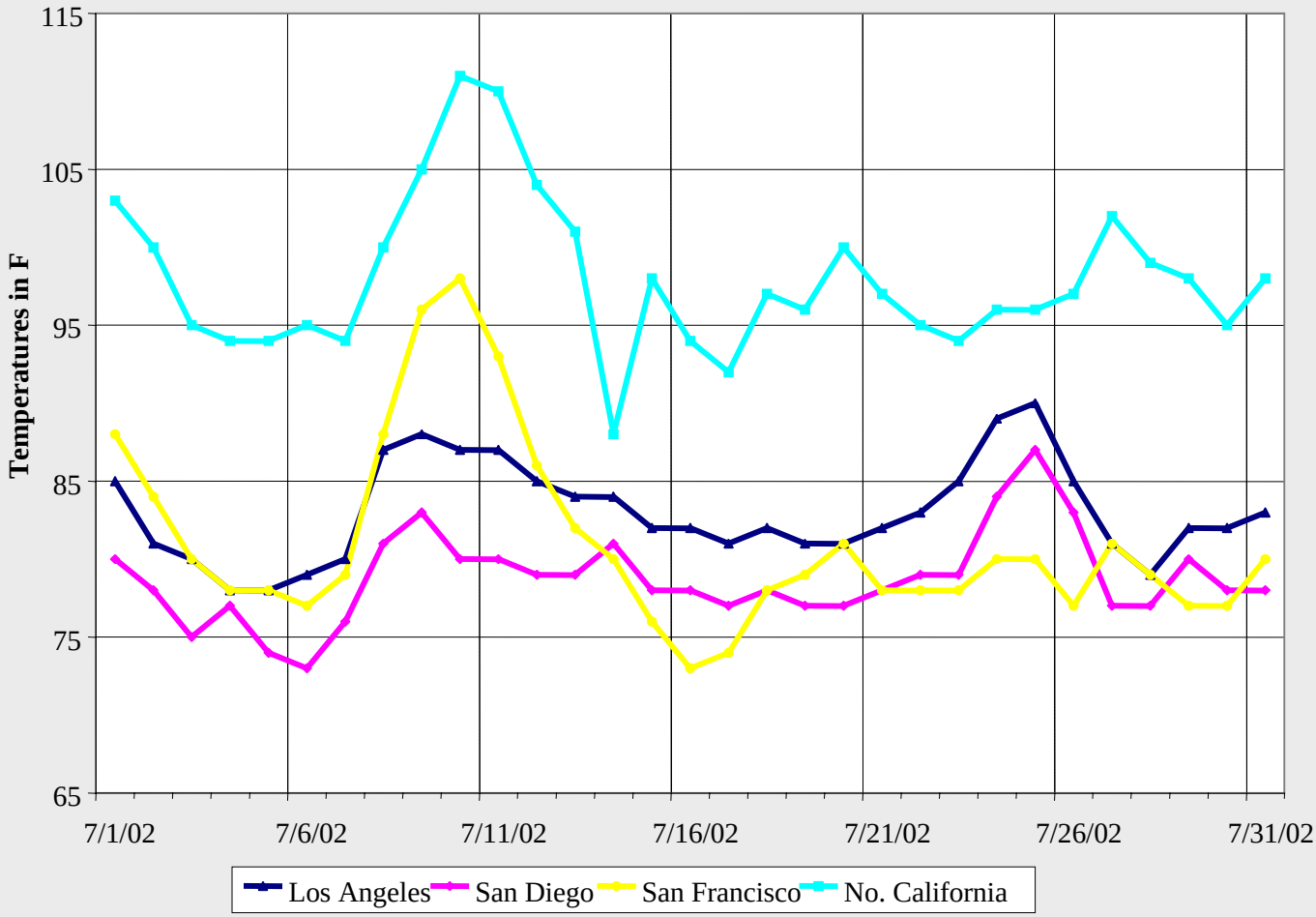
In July, the natural gas monthly average price dropped slightly from June, except for PG&E Citygate, which remained unchanged. The natural gas daily average prices remained stable during the second half of July with the price spread drawing closer and ranged from $2.4 MMBtu to $3.1 MMBtu.

The natural gas daily average price at Malin remained sharply lower than the other hubs on July 1 through July 3, however the daily average prices increased steadily throughout the next several days as Bonneville Power Administration (BPA) reduced hydroelectric generation for those dates. The lower natural gas price at Malin for this period was due to abundant hydroelectric generation in the northwest. In addition, the transmission line constraints at COI reduced the flow of hydro generation in the northwest region that might have otherwise been exported.

Source: "Spot Gas Prices." July 1, 2002 – July 31, 2002. Power Market Today. Online. Natural Gas Intelligence Online. August 2002.

Temperatures Across California

July 2002	Los Angeles	San Diego	San Francisco	No. California
Average Daily Temperature (°F)	83.0	78.7	81.1	98.0



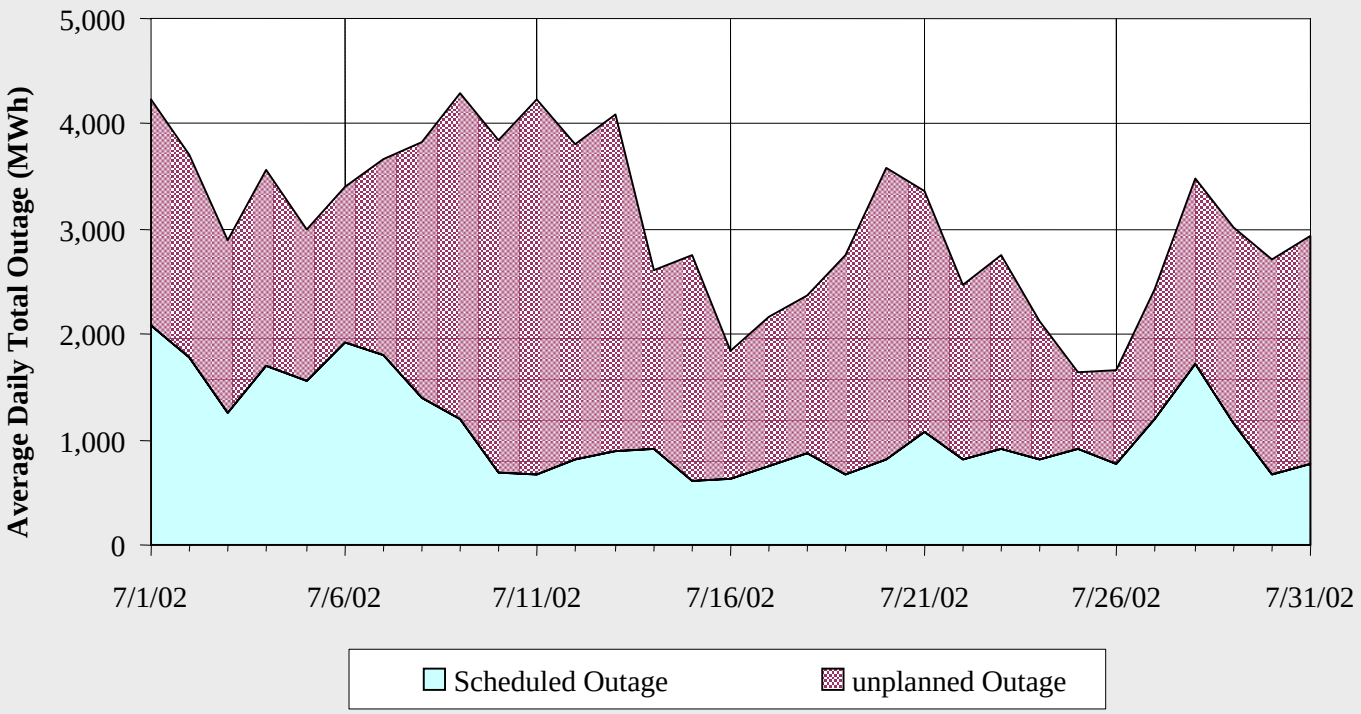
Northern California average temperatures remained considerably higher than the other locations throughout the month of July, particularly during July 9 through July 13 when northern California and the San Francisco Bay area experienced a heat-wave.

Source: California Independent System Operator. Grid Operation Actual and Forecast Data July 1, 2002 – July 31, 2002. September 2002.

Unit Outage

July 2002 Daily Constrained Generation	Scheduled Outage* (MW)	Unplanned Outage** (MW)
Average	1,127	2,045
Maximum	2,086	3,557
Minimum	607	747

Top 5 Generators with Scheduled Outage		Top 5 Generators subjected to Unplanned Outage	
Unit Name	Constrained Capacity (MW)	Unit Name	Constrained Capacity (MW)
Huntington Beach Unit 5	123	Pittsburgh Unit 7	257
Moss Landing Unit 7	107	Ormond Beach Unit 2	219
SONGS Unit 2	80	Delta	152
San Bernadino Unit 1	64	Four Corners	102
San Bernadino Unit 2	62	Pittsburgh Unit 2	99



In July, the daily average unplanned outage at 2,045 MW increased by 27 percent from June at 1,607 MW. Pittsburgh Unit 7 and Ormond Beach Unit 2 generation units predominantly contributed to the unplanned outages.

In July, the scheduled outages were lower by 60 percent, down from June.

*Scheduled Outage: generating units not in operation due to planned maintenance, scheduled closures, refueling, or other planned occurrences.

**Unplanned Outage: generating units not in operation due to breakdowns, storms, or other unplanned occurrences.

Source: California Independent System Operator. CAISO Data July 1, 2002 – July 31, 2002. August 2002.